COMMONWEALTH OF MASSACHUSETTS
BEFORE THE
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

An Investigation By The Department Of Telecommunications And Energy Regarding The Assignment Of Interstate Pipeline Capacity Pursuant To <u>Natural Gas Unbundling</u>, D.T.E. 98-32-B (1999).	))))	**D.T.E. 04-1**

INITIAL COMMENTS OF ENERGY EAST SOLUTIONS, INC.

Pursuant to the Order Opening an Investigation Regarding the Assignment of Interstate Pipeline Capacity issued in the above captioned docket January 12, 2004 ("January 12 Order"), Energy East Solutions, Inc. (Energy East Solutions) respectfully submits these initial comments.

I. RECOMMENDATIONS IN A NUTSHELL

Energy East Solutions respectfully urges the Department to take two principal steps in this proceeding:

1. ***Substitute a "path" approach for capacity assignment , similar the approach used in Rhode Island, for the current Capacity Fragmentation Policy.*** The Department should move to end, effective November 1, 2004, its Capacity Fragmentation Policy (as known as the "slice-of-the-system" approach adopted in 1999), and replace it with a modified version of the policy adopted by the Rhode Island PUC several years ago that allows suppliers to select among capacity paths while paying a surcharge (or receiving a credit) for any differential between the price of the particular capacity paths selected and the average cost of the LDC's capacity portfolio. While certain aspects of the Rhode Island approach need improvement, it clearly offers a time-tested model in a market that is very analogous to Massachusetts. The path approach should thus form the basis for a reformed Massachusetts policy and lay the basis for an expanded competitive market.

2. ***Address several operational issues where experience under the Model Terms and Conditions has shown the need for reform.*** The Department should also address a number of operational issues that adversely affect operations in the current marketplace, including in particular:

   (a) Correct the operational mismatch *between industry-standard* nomination deadlines for holiday periods and the *patchwork* of holiday nomination procedures that currently prevail among the different LDCs;

(b) Ensure that suppliers have *access (by meter) to the base load and temperature-sensitive components of the algorithms* used for non-daily metered customers so that suppliers may more accurately plan for and meet actual market requirements.

(c) *Correct the LDC algorithms for those summer months that include a factor for temperature sensitive usage where such temperature sensitive usage does not in fact occur*, thereby removing a source of unnecessary discrepancy between nominated and actual volumes.

The advisability of these changes does not depend on the presence or absence of competition in the upstream capacity markets. Nor do they raise any questions with regard to reliability of service, cost shifting among customer classes, or the LDCs future role in the merchant function or in planning and procuring pipeline capacity. Nevertheless, and for the reasons were fully detailed below, Energy East Solutions respectfully submits that these real-world operational changes will do far more to enhance competitive alternatives for gas consumers in the Commonwealth than the broader policy changes on which comment has been invited. Accordingly, we respectfully urge the Department, *regardless of its findings with regard to the architectonic issues,* to initiate appropriate proceedings to implement these far narrower policy recommendations effective November 1, 2004.

II. THE NEED TO REPEAL THE DEPARTMENT'S "CAPACITY FRAGMENTATION POLICY"

Energy East Solutions is an indirect, wholly-owned subsidiary of Energy East Corporation. The company has been active in the Massachusetts retail market for over a decade and is one of the most experienced suppliers of competitively priced natural gas in the Commonwealth. The company serves a full spectrum of commercial, industrial, and governmental customers located on the distribution facilities of several different LDCs in the Commonwealth, including many small retail customers. Accordingly, the company, together with its customers, has a vital interest in the workability of the operational terms and conditions applicable to retail gas supply in Massachusetts. It was for this reason that the company took a leadership role in helping craft the Model Terms and Conditions which were developed in the Gas Unbundling Collaborative several years ago and which were ultimately adopted by the Department and incorporated into the tariffs of the gas utilities.[1]

[1] The Draft Model Terms and Conditions as filed with the Department (and which have been largely adopted through the various individual tariff filings of the LDC) are available on the DTE website at: http://www.state.ma.us/dpu/gas/00-26/finalmodel.htm.

A. How we got here: a brief review of the Department's Capacity Fragmentation Policy

On January 12, 2004, the Department initiated an investigation regarding the assignment of interstate pipeline capacity in this docket (the "January 12 Order"). The Department stated there that its objective is "to determine whether the upstream capacity market is sufficiently competitive" to allow the voluntary assignment of interstate pipeline capacity rights by the local gas distribution companies to other entities. *January 12 Order, supra*, at 1.

Energy East Solutions applauds the Department's initiative in re-examining the Capacity Fragmentation Policy adopted in 1999, but would respectfully submit that the pressing issue is not the somewhat theoretical issue of the competitiveness of the upstream capacity market that serve New England (which, we believe the Department will likely find is not as competitive as one might wish), but rather is far more concrete: what is the best alternative to mitigating the operational costs and risks imposed on the market through the current Capacity Fragmentation Policy.

It is in the same cooperative and collaborative spirit that Energy East Solutions brought to the discussions several years ago that we submit these comments and must nevertheless regretfully inform the Department that, contrary to the Department's expectations in the late 1990s, there appear to be *fewer* competitive suppliers in this market, *fewer* transportation customers, and a *smaller* percentage of the market converted to transportation service than five years ago.

This is not a pleasant report; but it is in our considered judgment accurate nonetheless. Moreover, while unpleasant, it is not unexpected: Energy East Solutions predicted exactly this result in 1997, when it petitioned the Department to address the then-new problem of fragmentation of upstream capacity. *See* Petition of XENERGY, Inc. filed February 24, 1997 in D. P.U. 97-22 (hereafter, "the 1997 Petition").[2] As detailed below, the 1997 Petition warned that the capacity fragmentation policy then first being implemented would have exactly these adverse consequences:

> [The] fragmentation of the upstream contracts will impose burdensome costs and increased risks on new entrants . . . raising serious questions whether . . . other suppliers can proceed with marketing endeavors . . . .

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[2] On August 10, 2001, the Department issued a letter order finding the Petition to be moot in light of its orders in the *Natural Gas Unbundling proceedings* (D.T.E. 98-32-A (1998), D.T.E. 98-32-B (1999), D.T.E. 98-32-C (1999), D.T.E. 98-32-D (2000), and D.T.E. 98-32-E (2000). The August 10, 20001 letter is at http://www.state.ma.us/dpu/gas/97-22/816letorder.pdf. The proceeding was closed effective August 16, 2001. As the proceeding has been closed, the actual 1997 Petition is no longer available on the Department's website.

1997 Petition, at 4. Indeed, the fragmentation of capacity being implemented then was:

> "[s]o much at odds with the day-to-day reality of providing retail marketing supplies and services that few suppliers are likely to try to enter [that] marketplace. The system will simply not allow the emergence of the kind of retail marketing that the Department clearly intends.

Petition, paragraph 12, at 12.

The problem was that the upstream capacity rights that a customer received when it converted to transportation consisted of a "slice" of the LDC's entire portfolio of upstream transportation and downstream storage rights, such that the right to city gate delivery point capacity translated into literally dozens of increasingly smaller fragments on each of the upstream transporters. The fragmentation was so severe that 100 Dth of city gate delivery point capacity was rounded off to 0 Dths at some receipt points -- an absurd and unworkable result. 1997 Petition, *supra*, at 5-8. *See especially* Table I showing how 100 Dth of city gate delivery capacity was fragmented into 38 separate fragments, some as small as two-tenths and three-tenths of a single Dth). Of particular note, the 1997 Petition did not question the appropriateness of LDCs receiving full compensation for their entire portfolio of capacity rights, but merely focused on the intensely practical problems created through capacity fragmentation under the "slice-of-the-system" approach.

The Department responded to this narrowly-drawn Petition (as well as to requests by others urging a broader agenda), by convening an industry-wide Collaborative with directions to examine the full range of issues raised by complete LDC unbundling.[3] In the context of the public hearings, concern was raised over the potential for suppliers "cherry picking" the less-than-system-average cost capacity rights, leaving the costs of the greater-than-system-average cost capacity rights to be borne by those consumers who continued to buy their gas supplies from the utility. While some efforts were made to resolve this matter, no resolution was reached and the parties focused on other issues where more progress appeared likely -- such as the quite successful effort to produce a set of Model Terms and Conditions governing a host of operational aspects of the relationship between LDCs and competitive suppliers.

The capacity fragmentation issue was not resolved, however. When the Department finally ruled on the matter in 1999, it assumed that adopting a voluntary

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[3] The July 18, 1997 order instituting the Collaborative and directing that the issues raised in the 1997 Petition in 97-22 be considered there is available on the Department's website at: http://www.state.ma.us/dpu/gasunb.pdf.

"capacity path" approach would *necessarily* entail cost shifting and that only a mandated assignment of a full "slice-of-the-system" could prevent such shifting:

> Once it has been determined whether capacity will be assigned on a mandatory or voluntary basis, the parties will decide whether these assignments will be made either on a "path" or on a "slice-of-system" basis. . . . Under a "path" approach, the LDC would assign a pro rata share of capacity along a specific contract path of the interstate pipeline system from the well head to the city gate. The path approach assigns an uninterrupted route of capacity to a customer, based on linear segments of pipeline capacity that are used to serve this customer. *Under a path approach, customers within an LDC's distribution may experience different pipeline costs, because the pricing for different paths may vary.* Under a "slice of-system" approach, the LDC would assign a pro rata share of each upstream contract in the company's portfolio to the customer. *Under this approach, the customer is assigned capacity at the LDC's average cost of capacity.*

D.T.E. 98-32-B, issued February 1, 1999 (hereafter the "1999 Capacity Order"), *mimeo* at 14 (citations omitted, emphasis added).[4] *See also* note 19 (stating that under path approach, customers migrating to transportation early will select least expensive capacity while those remaining will be burdened with less desirable and more expensive capacity).

As a result of these concerns over what the Department seemed to perceive as an inevitable shifting of costs that would result from any variation of the "path" approach to allocating upstream capacity, the Department effectively mandated state-wide application of capacity fragmentation through the "slice-of-the-system" methodology. The Department believed that a mandatory, slice of system assignment regime would maintain reliability and avoid the "improper transfer" of cost responsibility until the upstream market should become workably competitive. The Department promised the public, however, that it would review operation of the statewide "slice-of-the-system" capacity fragmentation policy after three years, which is, of course, the instant proceeding.

B. Market response to the 1999 Capacity Fragmentation Policy

The consequences of the new policy were several. First, the participants in the Collaborative immediately devised an interim settlement that limited the worst aspects of

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[4] The 1999 Capacity Order is available on the Department's website at: http://www.state.ma.us/dpu/gas/98-32/98-32-b.htm. In addition, there are links to most of the relevant orders in the 98-32 series on the Department's Gas Unbundling Collaborative website at: http://www.state.ma.us/dpu/gasunb.htm.

the new Capacity Fragmentation Policy by largely exempting then-existing customers from operation of the new policy, thereby preserving competitive alternatives for at least that portion of the market. [5]

Second, suppliers came to terms with the prospects for operating under the new rules. Some suppliers exited the Massachusetts market altogether. Others closed down or failed. Others focused their business on those particular markets that could be served notwithstanding the new policy. Indeed, it is Energy East Solutions considered opinion that the Department's Capacity Fragmentation Policy has been *one of the principal restraints on the development of competitive retail access in the Commonwealth over the last five years* and has stunted the development of competitive retail markets in the Commonwealth for exactly the reasons detailed in the 1997 Petition.

C. Where do we go from here?

1. *Set prices to follow services rather than curtail service because the prices are wrong.* The tragedy, of course, is that all this was totally unnecessary. The Department's well-founded objective of preventing "cherry picking" of capacity paths (with resulting cost shifting) could have been addressed without mandating the fragmentation of upstream capacity. As will be detailed allow, the Rhode Island Public Utilities Commission has for several years now implemented an approach that provides suppliers far more flexibility in selecting contract paths for upstream capacity while surcharging or crediting the supplier for any differential between the *actual cost* of the contract paths selected and the *average cost* of the LDC is capacity portfolio. This rather simple approach vastly reduces capacity fragmentation, maximizes operational flexibility and precludes cost shifting. We respectfully suggest that such an approach can easily be adapted to the Massachusetts market (which is served to a large degree by the same portfolio of upstream pipelines).

In mandating capacity fragmentation in 1999, the Department seemed to treat the then-prevailing pricing rules for transportation services as immutable and hence concluded that the only solution was to force customers who wanted to convert to competitive supply in the future to buy capacity fragments they could not readily use since under the then-prevailing pricing rules allowing customers to select particular paths would have resulted in varying costs.

Energy East Solutions respectfully suggests that the matter can -- and should -- be viewed the other way 'round: the regulated utilities should offer those services under operational terms that are best adapted to meet the competitive policy objectives set by the Department while charging fair and compensatory prices approved by the Department

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[5] The settlement was filed on April 2, 1999 and approved by the in D.T.E. in D.T.E. 98-32-C. *See* Joint Motion For Approval Of Settlement Agreement, available on the Department website at:
http://www.state.ma.us/dpu/gas/98-32/motion.htm.

in light of the services being offered.[6] In short, if the current prices for needed services create cost-shifting incentives that are contrary to the public interest, the solution is to ***change the prices, not curtail the service.*** And after all, the review and revision of utility prices -- ***ratemaking*** -- is the very core of the regulator's competence and responsibility.

Accordingly, and as detailed below, we would urge the Department to change its focus here away from the question of the extent of competition in the upstream pipeline capacity markets and focus instead on crafting and implementing the best alternative to the Capacity Fragmentation Policy. Until the artificial cost and risk barriers created by this policy are removed, it is simply premature to consider the broader policy changes referred to in the January 12 Order.

2. The Rhode Island Solution. In addressing this issue, the Department need not write when on a blank slate. In neighboring Rhode Island, an approach was adopted shortly after the Massachusetts capacity ruling that addresses the fragmentation problem in a far superior manner. Under the Rhode Island approach as embodied in the tariffs of New England Gas Company, marketers, are allowed to select capacity paths to serve the requirements of their pools from among a universe of such paths posted by the utility on an annual basis. If the path selected by the marketer costs more than the average cost of the LDC's portfolio of upstream capacity, then the marketer receives a credit on its ancillary services bill from the LDC for the difference between its higher-than-average-capacity costs and the lower, system-average cost. Conversely, if the capacity path that is chosen costs less than the system average, then the marketer is surcharged for the differential. In this very simple manner, all customers pay the same share of the LDC's cost of holding a portfolio of upstream pipeline capacity regardless of the capacity path selected, while gaining far greater flexibly in selecting a path that will allow a supplier to assemble a competitive portfolio of gas supply that is tailored to that path. In RIPUC has explained operation of the system this way:

> The company makes available up to 20,000 MMBtu per day of capacity on six different pipeline paths to provide for transportation of gas by marketers to customers of ProvGas. Marketers are allowed to select the path or paths upon which they choose to acquire capacity. Each of the six paths has a specific surcharge or credit that is designed to result in the same average weighted price

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[6] It is worth noting that this was the fundamental approach adopted by the FERC in instituting open access at the pipeline level nearly 20 years ago. Before the reforms instituted beginning in 1985, pipelines rates were designed on the assumption that the pipelines were predominantly merchants, not carriers. This meant that pipelines frequently had a direct economic disincentive to opening their systems to third party suppliers. In adopting its new open-access policy in 1985, the FERC moved the pipelines towards providing the competitive services that the marketplace sought, while changing the pricing structures to recover their costs as open-access transporters.

> being charged for all upstream transportation. When the surcharge/credit is combined with the charges that the marketer pays directly to the pipeline, the resulting transportation cost is the same cost regardless of the path selected.

Report and Order in In Re: Providence Gas Company Annual Gas Charge Clause Filing, Valley Gas Company Annual Purchased Gas Price Adjustment Clause Filing and Providence Gas Company's Transportation Tariff Revision, issued October 17, 2001 in Docket Nos. 1673, 1736 and 3347, at 12.

The applicable provisions of the New England Gas Company tariff that set out the details of this approach are found principally in Section 1.07.0 of the company's Transportation Terms and Conditions, and are attached as an Addendum to these Comments.[7]

The Rhode Island approach is not perfect. What is does do, however, is offer the basis for a way out of the capacity fragmentation "box" in which Massachusetts finds itself. Accordingly, Energy East Solutions respectfully urges the Department to focus on this "path plus credit or surcharge model" and institute appropriate proceedings to adapt it to the practical realities of the Massachusetts market.

D. Specific responses to the Department's questions

The Department has specifically invited comments on the following five points:

1. The number of transportation customers;
2. The number of marketers;
3. The percentage of the market that has converted to transportation service (both in volume and number of customers);
4. Developments at the FERC regarding this matter; and
5. Mechanisms by which the LDC's can include other affected market participants in an LDC's capacity planning process.

As one competitive supplier, Energy East Solutions does not have access to statistical information responding to the first three of these questions. The LDCs,

[7] The entire tariff is available online at: http://www.negasco.com/stuff/contentmgr/files/70e595624404c5e4ec1f534a7e93178b/images/ritarif1103.pdf

however, do have this information and presumably will be able to answer these questions. Energy East Solutions is in a position to provide its understanding of market evolution based on anecdotal information and its own operations.

1. *" The number of transportation customers".* Based on anecdotal information, the company believes that, although some suppliers have added customers in some market segments, overall the total number of end-use customers served by competitive supply has probably diminished, as the minimum volume threshold required to achieve meaningful savings has risen due to the administrative and operational cost of doing business serving Massachusetts markets (due in not insignificant part to the Capacity Fragmentation Policy discussed above). The LDCs will presumably provide statistical information on this point, but it would not appear that there has been material growth over the last five years.

2. *"The number of marketers".* Again, anecdotal information suggests that the number of marketers active in the Massachusetts market has diminished significantly since the 1999 Capacity Order. Energy Vision, Enron, and AGF, among others have either ceased to exist or are no longer active.

3. *"The percentage of the market that has converted to transportation service (both in volume and number of customers)".* There does not appear to have been any significant increase, whether in volume or number of customers in the percentage of the market that has converted to transportation service.

4. *"Developments at the FERC regarding this matter*." With regard to developments at the FERC, we anticipate that other commenters here will provide the Department a full update and analysis of the implications of FERC's policies on capping prices for released capacity and in particular its recent ruling affirming its decision to eliminate the five-year matching cap for existing capacity subject to a right-of-first refusal (ROFR).[8] Of relevance here is this: if FERC's decision to eliminate the five-year term cap results over the long term in competitive pressure on LDCs to bid longer terms to retain capacity rights for system supply, then it will become all the more important for the LDCs to be able to mitigate that increased risk by enhancing the value of the capacity portfolio to customers -- which means minimizing capacity fragmentation. If, on the other hand, FERC's decision in fact results in LDCs signing shorter-term transportation agreements, then it will become easier for LDCs to manage their portfolio of upstream capacity, again allowing a reduction in capacity fragmentation for retail customers.

In any event, it may be years before the true effect of this ruling is felt because the most immediate effect is likely to be increased uncertainty as the matter is likely to be subject to further requests for rehearing and may well return to the Court of Appeals for

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[8] Order On Rehearing And Clarification, 106 FERC ¶ 61,088 (issued January 29, 2004).

further review. This regulatory uncertainty is likely to further complicate the Department's efforts to determine the competitiveness of the upstream markets -- which may well lead the Department to preserve a mandatory approach to capacity assignment at retail.

Energy East Solutions would reiterate therefore that the *pressing* issue in Massachusetts is not trying to divine the future policy of the FERC on rehearing or the potential decision of a Court of Appeals many months hence, but rather to *solve the problem at hand* in a manner that makes good public policy *regardless* of the outcome of these other proceedings. Hence, we would respectfully submit that developments at the FERC reinforce the importance of crafting an alternative to the existing Capacity Fragmentation Policy by adapting the Rhode Island approach as discussed above.

5. *"Mechanisms by which the LDC's can include other affected market participants in an LDC's capacity planning process".*

The key thing to remember is that the shipper's principal risk in contracting for a particular pipeline transportation path is the risk that the shipper's --*any* shipper's -- need for or ability to make use of that path will diminish over time while its obligation to make demand charge payments under the contract will not. Hence the question in contracting for long-term capacity is always about managing and minimizing that risk.

While various tools may be employed for managing this risk, the *single most important mechanism* for LDCs who seek to include other market participants in capacity planning *is to enhance the value* of the capacity under contract (or to be contracted): the more valuable the capacity, the easier it will be to find ways to manage the risk of underutilization.

As indicated above, by increasing the administrative costs and the risks of using assigned capacity, the Capacity Fragmentation Policy does the reverse. It *devalues* the LDC's portfolio of upstream pipeline capacity. Competitive suppliers are less able to offer customers attractive prices and services because they must plan for managing all the "dribs and dregs" of capacity fragments and are exposed to a host of unfamiliar -- and non-standard -- nomination practices, imbalance tolerances, cash-out provisions on each of the upstream fragments. This means that they are less able (and willing) to manage the pieces of upstream capacity that they are expected to be responsible for and will therefore be even less willing to take on added risk of incremental capacity, for example to help support load growth.

In Energy East Solutions' view, it is premature to discuss ways for LDCs to include competitive suppliers in the future capacity planning process until a solution is found to the present capacity fragmentation process. Until the market is able to rationalize the capacity paths, it will be very difficult -- unnecessarily difficult -- to integrate competitive suppliers in any formal, binding, manner into the capacity planning process.

Note also, that under the Rhode Island approach, the process is simplified because the LDC retains the responsibility of maintaining a portfolio of upstream pipeline capacity and downstream storage assets to meet the operational requirements of the end-use customers with the cost of this portfolio spread over all customers.

III. Operational issues where experience under the Model Terms and Conditions has shown the need for reform

In addition to the reform of capacity fragmentation, the Department should also act here to address a number of operational issues that adversely affect operations in the current marketplace.

A. *Correct the operational mismatch between industry-standard trading and nomination deadlines for holiday periods and the patchwork of holiday nomination procedures that currently prevail among the different LDCs.*

Over the last several years, industry standard practices have developed for gas trades around holiday periods that need to be reflected in the nomination schedules of the LDCs. The standard schedule reflected in the dates used by the Intercontinental Exchange (http://www.theice.com) addresses both US and Canadian holidays and sets dates for the various products traded (e.g. US Next Day, Canadian Next Day, etc.). While this schedule drives the procurement activities of the suppliers around holiday periods, there is a mismatch with the current patchwork of holiday nomination schedules among the Massachusetts LDCs. This mismatch prevents suppliers from tailoring supply acquisitions to market requirements as closely as could be done if the LDC holiday nomination schedules were synchronized to the standard market schedules. This of course exposes suppliers and consumers to increased risk of imbalances and cash outs around each affected holiday.

> ***Recommendation:*** modify the Model Terms and Conditions negotiated several years ago to synchronize the nomination schedules over holiday periods with current gas supply industry practice.

B. ***Ensure that suppliers have access (by meter) to the base load and temperature-sensitive components of the algorithms used for non-daily metered customers so that suppliers may more accurately plan for and meet actual market requirements.***

As the Department is aware, on most of the LDCs there are separate procedures for dealing with customers whose usage is metered on a daily basis (Daily-Metered Customers) and those whose usage is metered monthly only (Non-Daily Metered Customers). For Non-Daily Metered customers, the LDC uses an algorithm to predict usage over the month by adjusting the customers' base usage by a factor that reflects temperature-sensitive usage. For these customers, the LDC informs the suppliers what quantities of gas to nominate to each meter based on the number generated by the algorithm.

While the numbers generated by the algorithms are provided to the competitive supplier to use in gas supply planning and operations, the algorithms themselves are not. Hence, competitive suppliers can only "guestimate" the portion of the customers' gas usage that is temperature sensitive as compared to the portion that is not. This makes it more difficult than necessary for gas suppliers to tailor supply to the customer's load requirements, particularly when the weather changes abruptly (which frequently happens precisely during peaking periods when prices are apt to be particularly volatile).

While some customers (certain industrial customers in particular) may well have competitive and confidentiality interests in preventing the unauthorized distribution of their usage profiles, these concerns can obviously be addressed through appropriate non-disclosure terms. There does not appear to be any reason in principle why the base load and temperature sensitive components of usage behind a given meter cannot be disclosed to the supplier at the same time the transportation contract quantity numbers are provided, in order to assist parties in more accurately planning for and serving customer needs.

> ***Recommendation:*** amend the Model Terms and Conditions to require LDCs to provide this information to the supplier, by meter of each Non-Daily Metered Customer, at the time the transportation contract quantity numbers are provided, subject to non-disclosure conditions where appropriate.

C. Correct the LDC algorithms for those summer months that include a factor for temperature sensitive usage where such temperature sensitive usage does not in fact occur, thereby removing a source of unnecessary discrepancy between nominated and actual volumes.

Experience with the current algorithms for Non-Daily Metered Customers has also revealed that the algorithms in some cases include a factor for temperature sensitive usage where such temperature-sensitive usage does not in fact occur. This may arise, for example, during a summer month where a few cool days occur. The numbers generated by the algorithms produce a slight increase in consumption as though heating equipment was being turned on by the customer when in fact there is no increase in load above the non-temperature sensitive base. If the supplier accepts the number generated by the algorithm, it runs the risk of overdelivering gas that is not in fact consumed and purchased, producing instead a monthly cash-out that could have been avoided had the algorithm-generated quantify been more accurate.

Correcting the algorithms for those instances where this problem occurs would of course be assisted by the prior recommendation of separately providing the portion of the load that is temperature-sensitive and the portion that is not. In any event, however, the accuracy of the algorithm-generated quantities during summer months should be reviewed and enhanced by removing any temperature-sensitive load predicted by the algorithm where it does not in fact occur.

> ***Recommendation:*** Review summer month algorithms to remove any temperature-sensitive load predicted by the algorithm where it does not in fact occur.

IV. Conclusion

The recommendations made here do not turn on whether or not upstream capacity markets are more or less competitive than they were when the Department issued its 1999 Capacity Order. They represent serious, concrete steps that the Department can put into effect fairly quickly regardless of whether it determines to move toward or away from mandatory capacity assignment.

As explained above, the most pressing issue is ***not*** whether capacity assignment is “voluntary” or “mandatory”, but whether capacity is fragmented and devalued and the whole approach to administering assignment of such capacity more burdensome than is reasonably necessary. A mandatory assignment approach can be made much more “user-friendly” without material cost-shifting, without the need to divine the future course of FERC policy on “rights of first refusal” and without the need to address the future role of LDCs in the merchant function.

Energy East Solutions respectfully urges the Department to avoid the temptation to sacrifice real improvements to the pursuit of perfection and focus instead on those incremental enhancements that will make a real difference in the everyday operation of the marketplace.

WHEREFORE, Energy East Solutions prays the Department institute expeditious proceedings to adapt a "path" approach to capacity assignment in Massachusetts and to amend the Model Terms and Conditions as described above.

Respectfully submitted,

ENERGY EAST SOLUTIONS, INC.

By: ______________________________
Philip M. Marston, Esq.
Its Counsel

Dated: February 27, 2004
For filing: March 1, 2004

MARSTON LAW
218 N. Lee Street
Suite 300
Alexandria, VA 22314
Tel: 703-548-0154

Addenda:

Excerpts from Tariff of New England Gas Company
Holiday Trading/Nomination Schedule of Intercontinental Exchange

ADDENDUM

Excerpts from Transportation Terms and Conditions of New England Gas Company Section 6, Transportation Terms and Conditions, Schedule C, Sheets 11 through 14 (as published on the company website at http://www.negasco.com/stuff/contentmgr/files/70e595624404c5e4ec1f534a7e93178b/images/ritarif1103.pdf)

1.07.0 Capacity Release:

Each Marketer serving any Customer migrating from Non-Firm Sales, Non-Firm Transportation or Firm Sales Service to FT-1 or FT-2 Transportation Service or from another Marketer's Aggregation Pool where they were previously assigned pipeline capacity by the Company, will be required to accept, for each such Customer account, an assignment of a portion of Company's firm interstate pipeline transportation capacity at maximum rates for an initial term of up to one year. The Company shall determine the quantity to be released, based on a pro-rata percentage of the customer account's Average Normalized Winter Day Usage to the system total, and the pipeline on which such capacity will be released. The quantity of capacity shall be set forth in the confirmation materials provided to the Marketer. For all Customers classified as Medium, Large or Extra-Large this quantity will be reviewed annually against the Customer's most recent usage patterns. Any change in Customer's required capacity will be reflected in a revised capacity release with the Marketer for effect on the following November 1st. In the event that a marketer stops delivering gas on behalf of an existing capacity exempt customer, the customer will be prohibited from taking firm Company sales service. Such customers may select default transportation service as described in Item 2.04.0 below.

Marketer shall be required to execute a Capacity Assignment Agreement at the time a Marketer establishes an Aggregation Pool or any other instruments reasonably required by Company or interstate pipeline necessary to effectuate such assignment. Marketer is responsible for utilizing and paying for the assigned capacity consistent with the terms and conditions of the interstate pipeline's tariffs and this tariff. Marketer is responsible for payment of all upstream pipeline charges associated with the assigned firm transportation capacity, including but not limited to demand and commodity charges, shrinkage, GRI charges, cash outs, transition costs, pipeline overrun charges, annual change adjustments and all other applicable charges. These charges will be billed directly to the Marketer by the interstate pipeline.

All Capacity Assignments for FT-1 Transportation Service will be effective with the commencement of service. Capacity Assignments for FT-2 Customers will be effective the 1st of the upcoming month for Transportation Service Applications received prior to the 10th. For FT-2 Transportation Service Applications received on or after the 10th of the month, the capacity release will not be effective until the 1st of the month subsequent to the upcoming month.

Capacity assignments will be effective for an initial term of up to one year through the following November 1st. The capacity assignments shall be reviewed and re-released each November 1st and be subject to annual adjustment as described above. All releases hereunder will be subject to recall under the following conditions: (1) when required to preserve the integrity of the Company's facilities and service; (2) at the Company's option, whenever the Marketer fails to deliver gas in an amount equal to the Scheduled Transportation Quantity; and (3) any other conditions set forth in the capacity release transaction between the Marketer and the Company.

The Company shall assess a surcharge/credit to marketers based on the difference between the charges of the upstream pipeline transportation capacity and the weighted average of the Company's upstream pipeline transportation capacity charges as calculated by the Company. To the extent that the charges of such released pipeline capacity are greater than the weighted average charges, the marketer shall receive credit for such difference in charges based on the total quantity of capacity released by the Company to the Marketer. The per Dt charge is calculated by subtracting the charge per Dt for the released pipeline capacity from the Company's weighted average Upstream Transportation charges as identified in the Company's annual Gas Cost Recovery Filing. To the extent that the cost of such released pipeline capacity is less than the weighted average cost, the marketer shall be surcharged for such difference.

On or before August 1 each year, the Company shall calculate and provide to marketers, as defined in Section 6, Schedule C, Item 5.00, its best estimate of: (1) the over (under) recovery balance in its deferred gas cost account; and (2) the anticipated fixed costs for interstate pipeline capacity, storage and peaking supplies.

During the calendar month of September, each Marketer will be required to submit a new Capacity Assignment Agreement indicating pipeline capacity path references based on the available paths identified in the Company's annual Gas Cost Recovery Filing. Each Marketer shall identify pipeline capacity preferences for: (1) existing customers, and (2) any new customers. Marketer shall have the right to retain capacity released on existing paths if such paths remain available. Any changes from the Marketer's previous election will be effective November 1st in conjunction with the updating of customer capacity quantities described above. Subject to availability, Marketers may change path preferences for assignment of pipeline capacity during the year for any new customers added to their Aggregation Pool by filing with the Company a new Capacity Assignment Agreement with at least 30 days advance notice.

The capacity released to a Marketer stays with the customer account on which it is based and as such, will be reassigned at such time that a Customer terminates their contract with a Marketer or revert back to the Company as of the date of the customer's service termination.

Each Marketer's capacity assignment associated with Customers in an aggregation pool shall be reviewed on a monthly basis prior to the tenth (10th) calendar day of the month, and adjusted to reflect any net changes resulting from the addition and deletion of customers to the pool.

1.07.1 New Loads:
New Customers classified as Large or Extra-Large electing FT-1 transportation service will not be required to take assignment of the Company's capacity resources as described in 1.07.0 above. The consumption of such Customers may be subject to annual review and confirmation by the Company. Customers who fail to meet the minimum requirement for the Large classification shall be required to take assignment of the Company's capacity resources after no less than 60 days notice. Marketers for such customers may be responsible for obtaining citygate capacity at a specific citygate on the Company's system as determined by the Company. Such determination will be based on the customer's location, load characteristics and distribution system requirements. In the event that a marketer stops delivering gas on behalf of a customer without Company assigned pipeline capacity, the customer will be prohibited from taking firm Company sales service. Such customers may select default transportation service as described in Item 2.04.0 below.

ADDENDUM II

Holiday Trade Date/Flow Date Schedule

SOURCE: http://www.intcx.com/trading_hol_sched_NG.html

Special Natural Gas Trading Schedule for Next Day Instruments

Trade Date	Strip / Instrument	Flow Period
Christmas Break - Dec 25 & 26, 2003		
Wed, Dec24	Cdn Next Day	Thu25 - Mon29
Wed, Dec24	US Next Day	Thu25 - Mon29
New Year's Day - Jan 1, 2004		
Tue, Dec30	All Bal Month	Jan1-31
Wed, Dec31	US Next Day	Jan1-5
Wed, Dec31	Cdn Next Day	Jan1-5
Wed, Dec31	All Bal Month	Jan1-31
Martin Luther King Day - Jan 16, 2004		
Fri, Jan16	US Next Day	Sat17-Tue20
Fri, Jan16	CA Next Day	Sat17-Tue20
January 2004, Split Month End		
Thur, Jan29	US Next Day	Fri30-Sat31
Thur, Jan29	CA Next Day	Fri30-Sat31
Fri, Jan30	US Next Day	Sun1-Mon2
Fri, Jan30	CA Next Day	Sun1-Mon2

Fri, Jan30	All Bal Month	Feb1-29
Presidents' Day (U.S.) / Family Day (Canada)		
Fri, Feb13	US Next Day	Sat14-Tue17
Fri, Feb13	CA Next Day	Sat14-Tue17
February 2004, Split Month End		
Thur, Feb26	US Next Day	Fri27-Sun29
Thur, Feb26	CA Next Day	Fri27-Sun29
Fri, Feb27	US Next Day	Mon1
Fri, Feb27	CA Next Day	Mon1
Fri, Feb27	All Bal Month	Mar1-31
Good Friday		
Thur, Apr08	US Next Day	Fri9-Mon12
Thur, Apr08	CA Next Day	Fri9-Mon12
Victoria Day (Canada)		
Fri, May21	CA Next Day	Sat22-Tue25
Memorial Day / Split Month End		
Thur, May27	US Next Day	Fri28-Mon31
Thur, May27	CA Next Day	Fri28-Mon31
Thur, May28	US Next Day	Tue1
Thur, May28	CA Next Day	Tue1

Canada Day (Canada)		
Wed, Jun30	CA Next Day	Thu1-Fri2
Canada Day (Canada)		
Wed, Jun30	CA Next Day	Thu1-Fri2
Independence Day		
Fri, Jul02	US Next Day	Sat3-Tue6
Fri, Jul02	CA Next Day	Sat3-Tue6
July 2004 Split Month End / Civic Holiday (Canada)		
Thur, Jul29	US Next Day	Fri30-Sat31
Thur, Jul29	CA Next Day	Fri30-Sat31
Fri, Jul30	US Next Day	Sun1-Mon2
Fri, Jul30	CA Next Day	Sun1-Tue3
Fri, Jul30	All Bal Month	Aug1-31
Labor Day		
Fri, Sep03	US Next Day	Sat4-Tue7
Fri, Sep03	CA Next Day	Sat4-Tue7
Thanksgiving (Canada)		
Fri, Oct08	CA Next Day	Sat9-Tue12
October 2004 Split Month End		
Thur, Oct28	US Next Day	Fri29-Sun31
Thur, Oct28	CA Next Day	Fri29-Sun31

Fri, Oct29	US Next Day	Mon1
Fri, Oct29	CA Next Day	Mon1
Fri, Oct29	All Bal Month	Nov1-30
Thanksgiving (U.S.)		
Wed, Nov24	US Next Day	Thu25-Mon29
Wed, Nov24	CA Next Day	Thu25-Mon29
Christmas & Boxing Day (Canada)		
Thur, Dec23	US Next Day	Fri24-Mon27
Thur, Dec23	CA Next Day	Fri24-Tue28
New Year's Day / Split Month End		
Wed, Dec29	US Next Day	Thu30-Fri31
Wed, Dec29	CA Next Day	Thu30-Fri31
Thur, Dec30	US Next Day	Sat1-Mon3
Thur, Dec30	CA Next Day	Sat1-Mon3
Thur, Dec30	All Bal Month	Jan1-31

* Eastern Canadian trading points follow US Next Day schedule.
** CA Next Day include: Huntingdon, Sumas, Station 2, Kingsgate and AB Hubs.
*** ICE reserves the right to modify trading schedule. For further inquires please contact Bud Hum at 312.214.2040.

SOURCE: http://www.intcx.com/trading_hol_sched_NG.html